Chapter Eleven – Substations

I. Introduction

Substations are important facilities in a utility's electric delivery system. Substations change the voltages of electricity and connect generating stations, the transmission system, and the distribution system. Substations refer to the group of devices that receive electrical current from electrical power sources from overhead lines or underground cables, and distribute the current through other overhead lines or underground cables to other parts of the T&D system. Substations are important for the reliable operation of both the transmission and distribution system because they contain the transformers that change the operating voltages, the relays and circuit breakers to protect the transmission and distribution systems, the controls to switch loads, and the devices to monitor system conditions. Substation equipment is very complex and must be carefully planned, designed, operated, and maintained in order that a utility provide reliable electric service.

This chapter provides the results of Liberty's evaluation of ComEd's substations. The evaluation included all aspects of substations such as planing, design, operations, and maintenance. The objectives of Liberty's evaluation were to determine if: (a) ComEd's planning and loading of their substations was in accordance with their specifications and good utility practices, (b) ComEd's substation construction and upgrade planning, design, application, scheduling, and commissioning practices were adequate for providing reliable service with the expected load growth and temperature conditions and actual load growth and temperature conditions, (c) ComEd's planning, design, and application provided for adequate redundancy to prevent customer outages during maintenance periods and unscheduled equipment outages due to equipment failures and accidents, and (d) ComEd's substation equipment inspection, testing, maintenance, repair, upgrade, and replacement practices effectively minimized unscheduled equipment outages and were in accordance with good utility practices.

Liberty established the following evaluation criteria for its assessment of ComEd's substations:

(1) Substation planning, engineering, design, equipment selection, scheduling, construction, upgrades, commissioning, and maintenance should have been consistent with good utility practices.

(2) Substation planning, engineering, design, equipment selection, scheduling, construction, upgrades, commissioning, and maintenance should have resulted in reliable service to customers during severe weather conditions, accidents, and when equipment was removed from service for maintenance.

Liberty found that while most aspects of ComEd's substation designs were good, substation maintenance and the organizational structure responsible for maintaining and testing substation equipment was not consistent with good utility practices. Liberty provides its detailed conclusions and recommendations in sections III and IV of this chapter.

II. Background and Analysis

A. Substation Equipment

The following provides a description of the major equipment that is typically located in substations. This section is not evaluative, but rather is intended to help provide an understanding of T&D substations and the discussion in the following sections of this chapter. Also, please refer to the terms and definitions section of Chapter One of this report. Substations contain:

- *Switches* that change the flow of current or isolate lines, cables, or equipment from the power system.
- *Buses*, which are copper or aluminum tubes, bars, or wires, that conduct the currents passing through the substation.
- *Switchgear*, which refers to switches, circuit breakers, and sometimes transformers.
- *Insulators and equipment insulation* that prevent unintended flow of currents.
- *Circuit breakers, circuit reclosers, and circuit switchers* that interrupt load, overload, and fault currents, and sometimes change the flow of current.
- *Fuses* that interrupt fault current only.
- *Lightning arresters* that protect insulators and equipment insulation from overvoltages caused by lightning and switching.
- *Overhead grounded shield wires or masts* that reduce the chance of a direct lightning stroke to other substation equipment.
- *Grounding system* that provides a low resistance path for high currents produced by lightning and short-circuits.

- *Power transformers* that change the source voltage to a lower or higher load voltage (or in a few cases shift phase angles to control power flow).

- *Voltage regulators and Load Tap Changers (LTCs)* that "fine tune" the load voltage. LTCs are voltage regulators that are an integral part of a transformer.

- *Cables* that are insulated conductors.

- *Capacitor banks,* which improve the system power factor, provide voltage support, and reduce the load on substation transformers, transmission lines and cables, and generators.

- *Inductors* that are used either to increase line or neutral impedance to limit fault current or, on some high voltages systems, to counter the elevated voltages caused by transmission line capacitance.

- *Relaying systems* that protect the lines, cables, and substation equipment. Relaying systems measure system quantities, react to abnormal system conditions, and automatically control circuit breakers, circuit switchers, or reclosers to minimize equipment damage and unnecessary equipment and circuit outages.

- *Monitoring systems* that provide real-time information to system dispatchers.

- *Supervisory Control and Data Acquisition (SCADA) equipment* that allows the load dispatchers to receive data from the substation monitoring equipment and to directly control load flow and by operating circuit breakers and motor-operated switches.

B. ComEd's Substations

ComEd's nominal system voltages were 765kV, 345kV, 138kV, 69kV, 34kV, 12kV, and 4kV. Utilities normally classify 765kV, 345kV, and 138kV systems as "Transmission" systems, 69kV and 34kV as "Sub-Transmission" systems, and 12kV and 4kV as "Distribution" systems. ComEd classified 765kV, 345kV, 138kV, and 69kV as "Transmission," and 34kV, 12kV, and 4kV as "Distribution."

Most utilities have two classifications of substations: transmission substations and distribution substations, as determined by their primary purpose. Transmission substations are those that provide voltage transformation or switching among the transmission and sub-transmission systems. Distribution substations are those that provide voltage transformation from a transmission or sub-transmission voltage to a distribution voltage, or from one distribution voltage to another. ComEd's classified substations as follows:

- **Generating Station Switchyards** step up voltage from a generating station to 138kV or 345kV. ComEd had 17 Generating Station Switchyards.
- **Transmission Substations *(TSS)*** step down voltage between transmission systems. Some TSSs have 12kV distribution and are identical to TDCs. ComEd's system had 135 TSS substations.
- **Transmission/Distribution Centers *(TDC)*** step down voltage between 138kV transmission and 12kV distribution systems. ComEd's system had 98 TDC substations.
- **Electric Service Substations *(ESS)*** provide 69kV, 34kV, 12kV, and 4kV for a single customer. ComEd's system had 1,954 ESS substations.
- **Substations *(SS)* and Distribution Centers *(DC)*** provide 12kV and 4kV for general distribution. ComEd had 546 SS and DC substations.
- **Network Centers *(NC)*** provide voltage transformations from 12kV or 4kV to low voltages (120V/208V and 277V/480V) via network protector transformers. ComEd had 253 Network Centers with about 2,000 network transformers and protectors.

C. ComEd's Substation Organization

Organizational Structure of Substation Construction and Maintenance Group

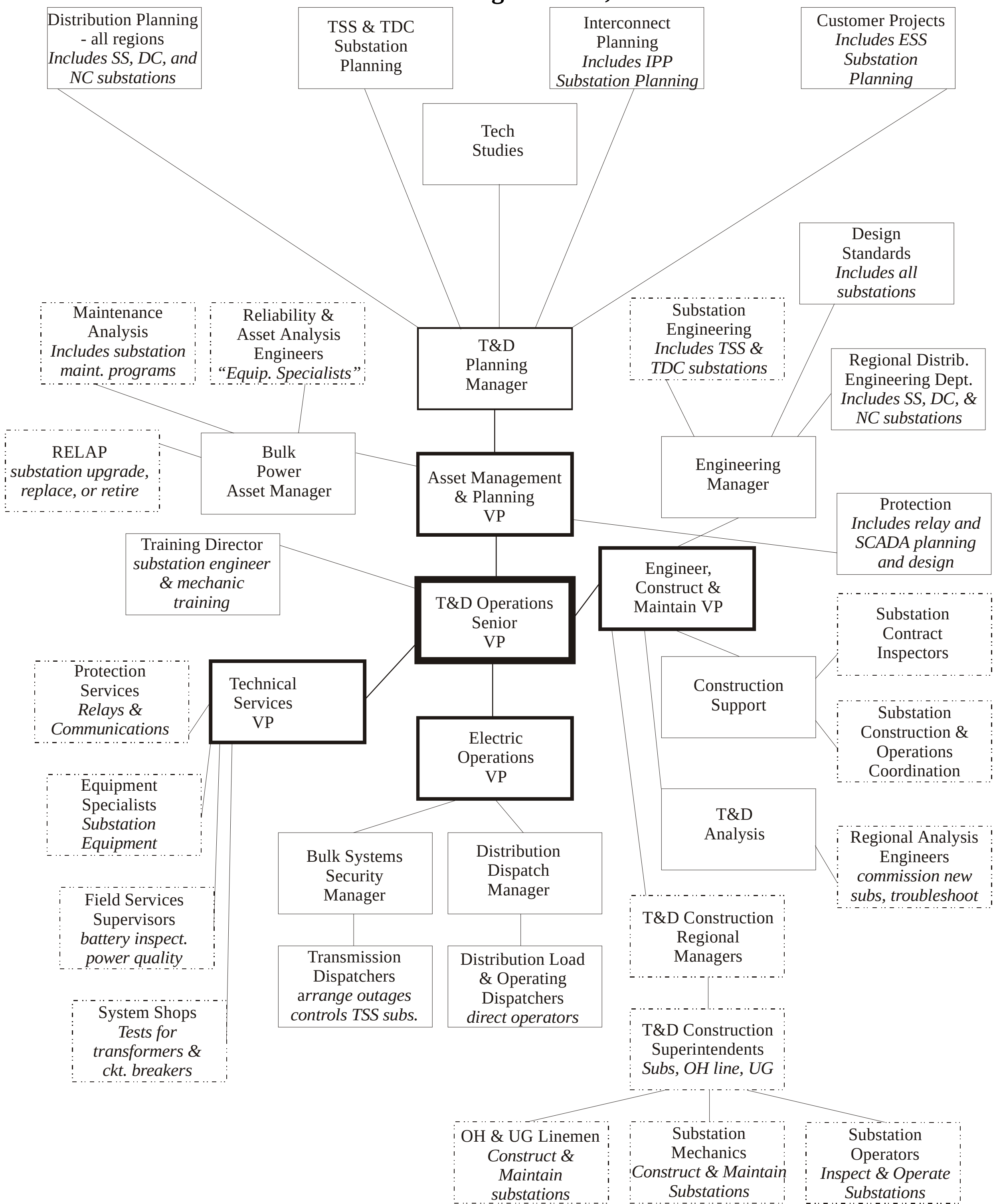
For construction and maintenance responsibilities, large electric utilities typically use centralized transmission organizations and regional, but separate, organizations for substations and distribution systems. This organizational approach is founded on the special skill requirements for each organizational element and on having defined regions with similar equipment. Since the equipment and skills required for constructing and maintaining transmission substations and distribution substations are similar, the same regional substation groups perform both. However, the skills and equipment required for constructing and maintaining distribution systems are substantially different from that required for substations, and therefore distribution groups and substation groups are typically separate.

ComEd's organization prior to 1997 included separate regional substation and distribution groups, but since 1997, these groups have been combined (Refer to Chapter Two – T&D Organization). ComEd's Engineer, Construct, & Maintain *(EC&M)* organization included engineering, construction, and maintenance for transmission, distribution, and substations. Not only were various substation construction and maintenance support functions scattered among several groups within the EC&M organization, but also some were not even part of the EC&M organization. The Engineering (design) group provided field engineers for special projects, and the T&D Analysis group provided personnel assigned to the Transmission Analysis Engineers *(TAEs)* to test and maintain substation relays and controls, to investigate substation problems, and to commission new substations and upgrades.

Regional T&D Construction Managers were responsible for the construction and maintenance of the distribution systems and substations within their regions, and depended on engineers from other groups for technical expertise. The substation mechanics and the distribution electricians (linemen) were under one regional management organization, without regional substation managers and engineers solely responsible for the construction, upgrading, and maintenance of ComEd's 2,750 substations. The lack of regional substation management and engineering expertise reduced the focus and possibly the quality of work at substations. ComEd's substation organizational structure was not consistent with that employed by other large utilities.

The figure below shows a simplified functional and organizational structure of the elements of ComEd's organization that were involved with substations as of the summer of 1999. It shows the organizations involved with ComEd's substation planning, design, upgrade, and construction, maintenance, and operation.

ComEd's Substation Organization, Summer 1999



Note: The broken line boxes indicate the organizational elements that typically are part of a separate "Substation Construction and Maintenance Organization."

ComEd's Substation Skilled Personal

Since ComEd's substation operators and mechanics shared their management with distribution electricians (linemen), and since the regions did not have their own regional construction and maintenance engineering staff, the organization required that substation operators and mechanics and their supervisors accept considerable responsibility for the reliability of substations. The TAEs, system substation engineers, and the equipment specialists provided great assistance. However, they covered the entire system. The general knowledge and enthusiasm exhibited by these groups was impressive. Liberty found that ComEd provided adequate training programs for the field engineers. The skills of the engineers responsible for the commissioning of substation equipment, as well as the maintenance and trouble-shooting of relaying and control systems, met good utility practices. Liberty found that ComEd provided adequate training for the substation operators to perform switching and inspections, and substation mechanics for performing substation construction and equipment installation work.

While the construction skills of the substation mechanics were impressive, their maintenance skills were not. One observation of a maintenance crew in action was disappointing. It was not clear whether basic test equipment was unavailable, or if the mechanics lacked the skills to use basic test equipment. Liberty observed ComEd mechanics performing 12kV circuit breaker maintenance at the Kingsbury-Ohio substation. They did not have a copy of their work procedures, did not perform any tests to verify the electrical integrity of the breaker, used an improper lubricant, and exposed spare circuit breakers to damp outdoor air. This lack of following good utility practice indicated either the need for additional training or better technical supervision.

ComEd did not have substation test crews specially trained and equipped to perform the more complicated acceptance and maintenance tests required by the work procedures. When available, the System Shops electricians were called to perform special power-factor and circuit breaker motion analysis tests. The number of test sets (one of each) and qualified shop electricians (two or three for each test set) to operate the test sets was insufficient. A nearby utility about one-half the size of ComEd had18 substation maintenance and testing crews, plus 11 more crews that specialized in performing insulation power-factor tests. This utility used 11 power-factor test sets and 12 circuit breaker motion analyzers.

Using ComEd's Skilled Workers for Non-ComEd Projects

In July 1999, ComEd employed 509 substation mechanics. ComEd sometimes used these mechanics for non-ComEd projects. During the period of January 1998 to August 1999, ComEd pursued the sale of electrical construction and maintenance services, and provided engineering and skilled labor to perform construction, maintenance, or repair work for about 200 non-ComEd projects. Of these, about 120 projects used ComEd linemen and substation mechanics. While some of these projects were important to the reliable operation of ComEd's system, the practice of using ComEd's mechanics and electricians for outside work, during a period when ComEd's own maintenance backlog was significant, was not consistent with good utility practices.

Outside Contracting for Substation Maintenance

ComEd used contractors to perform a few specialized maintenance procedures in substations. The tasks included energized insulator cleaning, infrared thermography, ultrasonic inspections, some minor relay testing, and transformer LTC (load tap changer) testing and dissolved gas-in-oil analyses. ComEd did not use contractors to perform any other substation maintenance, except for contractors who performed commissioning tests for non-ComEd IPP (Independent Power Producers) substations. ComEd indicated that it was not prohibited from contracting to outside companies for the performance of substation equipment maintenance. Not using the services of quality substation maintenance contractors, when the substation maintenance was significantly backlogged, was not consistent with good utility practices.

D. Substation Planning and Transformer Load Forecasting

The T&D Planning group, under the Asset Management Department, performed all substation planning. This organizational structure is typical of other utilities.

ComEd's T&D Planning group estimated distribution and transmission load growth each year for the upcoming five years, and prepared construction and upgrade plans for lines, cables, and substations. ComEd's regional distribution planners determined the likely increase or decrease in distribution feeder and substation transformer loads on the basis of the estimated increase of customer loads and scheduled construction and upgrades. The equipment ratings specialists provided limits for normal and emergency, winter and summer loading. Unless restricted by other equipment, planning practices used the ComEd transformer ratings for summer normal loading, without applying margins for under-estimations, for picking up loads from other transformers, or de-rating for transformers that had been previously overloaded. Liberty found examples of substantial differences between future planned substation loads and the actual loads. The amount of the summer peak load depends on ComEd's customer base loads and the ambient weather conditions. ComEd's planners determined future base loads from expected increases in connected loads. To compare peak loads due to changes in base loads from year to year, ComEd had to adjust the past years' peak loads to cancel or "normalize" the effect on the loads caused by weather conditions. In simple terms, the "normal" weather conditions were based on the average of the peak ambient temperature and humidity conditions for the peak days during the previous

15 years. Correction or "normalizing" percentages were applied to the distribution system loads as a whole, for each region, and for each type of customer. This resulted in determining what the annual peak loads would have been if the weather had been "normal." The normalized peak loads were determined using multipliers provided by ComEd's strategic analysis group and were used by ComEd's distribution planners as the starting point for forecasting future peak loads, without taking weather into consideration.

The use of normalized past peak loads was necessary to provide a non-weather-related basis for forecasting future loads. However, ComEd's planners also assumed that normal, or average, weather conditions (which equates to about 93°F) would occur on the peak load days in the future. Therefore, even if future base loads were properly predicted, there was a 50 percent chance that the actual loads, due to weather conditions, would have been greater than predicted. If ComEd had developed and applied more conservative multiplying factors to load forecasts for each type of customer load, the chances that the system components would be overloaded due to extreme weather conditions would have been reduced. Refer to Chapter Five – Distribution System Planning for additional discussion on this matter. Liberty found that ComEd was not conservative in its planning methods for substation loads.

According to ComEd's own study, if its system is not sufficiently reinforced and if the summer peak temperatures in 2000 match those experienced in 1999, the loading on about 30 percent of the TSS and TDC transformers and 16 percent of the feeders will exceed ComEd's normal rating. A few of the transformers will exceed 120 percent of the normal rating if temperature conditions are matched. This expected and very possible loading is the result of inadequate planning.

RELAP – Remaining Economic Life Assessment Policy

RELAP was a group of four engineers, formed to comply with a 1998 company policy, and that determined the necessity to replace, upgrade, or repair substation equipment to provide for reliability. In other words, RELAP had to estimate the remaining reliable life of substation equipment. The RELAP group received requests to replace substation equipment from field substation personnel. Typical reasons for these requests were safety considerations, lack of access to spare parts, uneconomic maintenance expenses, and poor equipment performance.

Once a request was accepted for consideration, ComEd held a meeting of personnel (generally a large group) from affected organizations, including substation planners, substation equipment specialists, and T&D foremen. This group inspected the substation, reviewed operating and maintenance problems, analyzed available loading and oil test data, and decided the action that should be taken. If it was decided to upgrade or replace substation equipment, the RELAP group then prepared a budget and requested the planning group to prepare plans for the corrective actions.

By initiating the RELAP program, ComEd indicated the need to evaluate and correct major substation problems, and by having the program ComEd has exceeded good utility practice. But, the program itself had a few problems. The practice of gathering a large group to perform the appraisal, although arguably necessary, caused long lead times before plans for corrective action were formulated. Aside from oil tests, insulation diagnostic testing (testing normally performed by other utilities) was not performed to help evaluate the condition (service age) of the equipment insulation, nor was overload history always considered. Comprehensive transformer loading records were not typically available.

Although planning and upgrade of substations for capacity reasons, and maintenance of substation equipment were handled by other groups, the RELAP group was largely responsible for determining when older substation equipment had become unreliable. RELAP fell short of its objective to estimate remaining service life of substation equipment by not including comprehensive insulation test evaluations and operating history.

Transformer Load Ratings

Well maintained transformers have a life expectancy that depends primarily on the ability of the cellulose insulation to insulate and to withstand the physical forces imposed on it. The insulation normally degrades at a slow rate, but deterioration is accelerated if the insulation is overheated. In fact, the rate of deterioration can increase exponentially with insulation temperature. Therefore, transformer loss-of-life depends on insulation temperature and the accumulated length of time the cellulose in the insulation is overheated. Insulation temperatures in turn depend on load currents, ambient temperatures, cooling efficiency, and internal energy losses.

ComEd's dispatchers could only monitor actual winding temperatures on a few transformers. They could, however, monitor transformer loads and over-temperature alarms for all TSS and TDC substation transformers. When winding temperature setpoints were exceeded, dispatchers were notified by alarms from the SCADA system. Dispatchers would then determine if load could be transferred to another transformer and would dispatch a substation operator to investigate. The operator would report the transformer temperatures and determine if any cooling problems such as dirty radiators or defective oil pumps existed. The radiators on a few transformers were designed such to make inspection difficult. ComEd had been modifying the radiators on those transformers to make inspection and cleaning more convenient. ComEd had started monitoring TSS, TDC, and highly loaded transformers on a more intense basis for dissolved gases in the transformer oil. Dissolved gas analysis (*DGA*) can indicate serious insulation deterioration.

Although not directly measured, the hottest insulation (hot-spot) temperature in a transformer is usually about 10° C more than the average winding temperature, which is indicated on the transformer's winding temperature gauge. And, according to ANSI/IEEE C57.92-1981 (transformer loading), aging greater than normal begins when the hot-spot temperature exceeds 110°C, or an average winding temperature of about 100°C. Since ComEd specified insulation with higher temperature rating (65°C rise) than the nameplate rating (55°C rise), the TSS and TDC transformers could be operated continuously at 112 percent of the nameplate rating MVA when the continuous ambient temperature is 30°C. The "rise" temperature is the amount of winding temperature above the ambient temperature that is expected as load increases. The insulation hot-spot temperature caused when a transformer was loaded to 112 percent of the nameplate rating, at the IEEE rated ambient temperature of 30°C, would be about 105°C (30°+65°+10°). If the ambient temperature was at the ComEd assumed 35°C (95°F) the hot-spot temperature would be about 110°C, the temperature at which the IEEE indicates that loss-of-life occurs.

ComEd specified that its TSS and TDC transformers could be operated for normal summer loads at 128 percent of the nameplate rating MVA when the ambient temperature was 35°C. The IEEE standards indicates that if a transformer was continuously loaded at 128 percent with a 35°C ambient temperature, some loss-of-life would occur. Additionally ComEd rated the transformers, under emergency conditions, to be operated to 155 percent of nameplate MVA for 10 days and 170 percent of nameplate MVA for 2 hours. According to the IEEE standard, substantial loss-of-life could occur at these ratings. Recently, ComEd started specifying that the oil temperature of new transformers could not exceed 85°C (188°F) when operated at the 155 percent rating. This was to assure that excess gas (which can cause winding failure) would not be produced in the oil when operated at the 155 percent rating.

The 10-day rating was to allow for replacement or repair of other equipment that failed and caused the overload situation. The 2-hour rating was to allow for switching to transfer loads to other transformers. As stated in ComEd's "General Distribution Planning Criteria," the justification for these ratings was that nameplate ratings were based on "continuous" loading, when in reality both the ambient temperatures and the load cycles throughout a day allowed the "real" rating to be increased. Neither the ComEd planning criteria nor the reply to Liberty's request for transformer loss-of-life calculations provided the data needed to thoroughly evaluate ComEd's transformer ratings.

To assess the validity ComEd's transformer ratings, the following information would have been required:

- The loss of transformer life that is accepted by ComEd. Utilities normally will accept some loss-of-life when transformers must be overloaded during emergency conditions.

From this starting point, the loading calculations (MVA and accumulated overload time) can be performed using either the IEEE tables or the manufacturer's factory load test results.

- The manufacturer's data indicating (1) if the insulation can withstand greater than the normal maximum 110°C hot-spot temperature, as indicated by IEEE and (2) the actual winding temperature rise of ComEd's transformers, regardless of that indicated on nameplates. It is possible that actual temperature rise was much less than indicated.

- The assumed operating conditions. Loss-of-life calculations depend on hot-spot temperatures caused by not only the accumulated overloading time, but also on the assumed load (temperature) before the overload condition. ComEd indicated that they assumed an ambient temperature of 35°C (95°F). The manufacturer's rating are normally based on a continuous ambient temperature of 30°C (86°F).

- The overload history of transformers. Excess aging due to overloading is a function of accumulated over-temperature time.

- Whether switching of transformer loads to relieve overloaded transformers always occurred within two hours.

- If replacement or repair of failed transformers or other equipment that caused transformer overload conditions always occurred within ten days.

Although ComEd had the means to record overload times, by the PI-Historian software using data from the SCADA system, it had not systematically analyzed the data for loss-of-life calculations. Since ambient temperature and operating conditions affected winding temperatures, the monitoring and archiving of winding temperature data during overload periods were necessary to more accurately predict transformer loss-of-life. ComEd had been manually recording temperatures on overloaded transformers, and more recently recorded using a few remote monitors, the data were not used to determine loss-of-life. ComEd used the results of the recently started dissolve gas analyses to monitor damage caused by overloading.

Liberty could not thoroughly evaluate ComEd's transformer ratings due to lack of data. Liberty's request for loss-of-life calculations referred only to the IEEE standard, without providing the data necessary to verify the ratings. However, on the basis of assumptions made by Liberty, ComEd's substation transformer normal ratings were appraised as slightly excessive and the emergency ratings were somewhat more excessive, when compared to the guidelines contained in IEEE standards.

Loading Parallel Transformers

ComEd operated their Chicago TSS and TDC substations with transformers paralleled (that is, with normally closed bus-tie breakers) to equalize unbalanced transformer loads and to provide uninterrupted service continuity if one transformer fails. When transformers are paralleled, they are de-rated to 95 percent of normal summer rating to allow for the impedance differences between transformers that cause one transformer to carry more load than the other through circulating current flow.

For any TSS or TDC substation with three or more transformers, if one fails (or is being maintained) the others may be paralleled. In this case ComEd requires that the substation loading be limited to the lowest of the following:

- Normal (no transformer outages) – all normal summer transformer ratings times 95 percent.

- Single contingency (one transformer de-energized) – the lower of (a) the normal rating of all transformer (including the de-energized transformer) times 95 percent, or (b) the remaining transformer summer emergency rating times 95 percent.

The normal summer substation rating times 95 percent was usually the limiting condition when one transformer failed and two or more other transformers are paralleled to carry its load.

Although the paralleling of transformers for normal conditions is controversial, for single contingency conditions (when one transformer is out-of-service), ComEd's practice of de-rating parallel transformer is in accordance with good utility practices.

E. Substation Design

The designs of ComEd's substations are very important because of the huge amounts of power flowing in the transmission system and lesser, but just as important, amounts of power in the sometimes extremely dense and complex distribution system. Some of ComEd's distribution substations were built by other utilities before ComEd acquired those utilities. The design of those substations may have used different design criteria and methods. Even those substations built by ComEd may have different design bases because of the distinct needs for different areas of ComEd's service territory. ComEd's territories includes the Chicago "Loop" and the surrounding urban area with a high commercial and residential load density requiring extremely high reliability, suburban residential and industrial areas with moderate load density requiring moderately high reliability, and rural areas with low load density and lessor reliability requirements. It cannot be expected, or even be possible, for ComEd to design, build, and operate a substation for the rural areas of Antioch, or even one serving suburban Waukegan, identically with one in downtown Chicago. The following is a description of ComEd's various substation bus arrangements.

TSS and TDC Substations

All TDC substations and some TSS substations had distribution circuits. ComEd made up its 345kV and 138kV transmission systems in two separate systems (referred to as Red and Blue) to provide redundancy and to reduce stress on circuit breakers. With one exception, all TSS and TDC stations contained at least two large power transformers, usually each connected to its own bus, that were each connected to one of the two transmission systems (red or blue). Substations in the Chicago region had "closed ring distribution buses" or "double distribution buses" with the bus-tie circuit breakers normally closed, paralleling the transformers. This arrangement allowed the transformers to share the intense Chicago loads and provided for uninterrupted service in case one transformer failed. The disadvantages of paralleling transformers are that phase and neutral inductors must be used to limit fault current and that parallel transformers are exposed to more distribution faults and circulating currents. The use of neutral inductors, especially when one inductor is used for several transformers, may cause neutral voltage disturbances and harmonic voltage distortions. The designs provide good reliability in terms of reducing short-term customer outages, but risk reducing reliability in terms of increasing substation equipment failures due to additional exposure to fault currents and overvoltages, and excessive system neutral voltage and harmonics.

In New York City, the local utility's (Consolidated Edison) substations operate with parallel transformers. Other utilities, for example Rochester Gas & Electric, purposely do not. Therefore, it cannot be said that ComEd's design and operation of Chicago's TSS and TDC substations was not consistent with other utility practices. Also, for some substations, considerable re-design would be required to re-distribute loads to allow for non-parallel operation. Liberty's concerns about operating transformers in parallel is the possible reduction of equipment life and the possible problems caused by the voltages and harmonics produced by the use of neutral inductors, particularly when one inductor is used by several transformers. Equipment in such substations should receive more frequent inspections, testing, and maintenance to monitor any deterioration; and protective relay systems testing should be intense to assure that the relays operate properly to minimize damage when distribution faults occur. Moreover, each transformer should have its own inductor to minimize neutral voltage problems.

Outside the Chicago region, TSS and TDC substations with two transformers had double distribution buses, with the bus tie circuit breakers normally open (*i.e.*, not in parallel). Therefore, no inductors were required. With this arrangement, there was less transformer exposure to distribution faults, but one-half of the distribution loads will be de-energized if a transformer fails until the bus-tie circuit breaker is closed. Automatic closing of the distribution bus tie-breakers for transformer failures provides for limited outage times and is consistent with good utility practices.

SS Substations, DC Distribution Centers, and NC Network Centers

The SS and DC substations were much smaller and had fewer distribution circuits than the TSS and TDC substations. Some had two or three transformers, but most had only one transformer. When there is a transformer failure in a single bus substation, load must be picked up from other substations by closing distribution line tie switches.

ComEd used NC substations in downtown Chicago and Evanston. They had 12kV or 4kV to 120/208 or 277/480 Volt transformers that had low voltage circuit breakers referred to as "network protectors." The secondary circuits of the network transformers were all common within a particular "network," allowing all transformers to share loads. If one primary circuit or a transformer failed, the network protector removed that transformer from the network without disturbing the customers' electric supply.

"Concept" Substations

Over the last few years, ComEd specified, purchased, and installed double-bus TDC and SS substations with the distribution switchgear, control panels, and relaying installed in a prefabricated metal building. The building and equipment were assembled, pre-wired, and tested at a factory, then split in half and transported to the site. After the halves were assembled on-site, the wiring was connected, the SCADA was installed, and the switchgear and relaying were ready to commission. These substations could be ordered and installed quickly (except the transformers), and the factory testing provided for good initial quality control. ComEd's use of the "concept" substations was an excellent utility practice.

F. Substation Construction, Upgrades, and Commissioning Quality

Regional T&D construction superintendents and crew leaders supervised substation construction and upgrades. Either the substation mechanics or contractors performed the work. Substation engineers, transmission analysis testing engineers, and others also were involved. Transmission analysis testing engineers performed commissioning tests on, and inspections of, new substations and upgrades. ComEd's substation commissioning was very comprehensive and performed by highly skilled engineers. On the basis of inspection of substation upgrades being performed, Liberty concluded that the equipment and cable installations and wiring was of quality workmanship.

ComEd was not able to complete some scheduled substation upgrades, such as at LaSalle and Northwest Substations, in timely fashion. The LaSalle 69kV to 138kV upgrade required nine years to complete. ComEd indicated that there were difficulties in obtaining permits and obtaining outages, but they also lowered the priority for completing the project for economic reasons. The delays in completing substation upgrade work jeopardized reliable electric service.

G. Substation Operations

Dispatchers at the Bulk Power Center *(BPC)* at Lombard controlled Transmission Substation *(TSS)* operation and switching. Dispatchers at the Distribution Dispatch Center *(DDC)* in Joliet controlled all other operations and switching. TSS and TDC loads and breaker positions monitored by the SCADA system were indicated on substation one-line diagrams displayed on video monitors. The dispatchers monitored loads, arranged for outages, and ordered substation switching from these two locations. Liberty found that the BPC and the DDC to be excellent in terms of efficiency and equipment. ComEd provided the BPC's and DDC's dispatchers, arrangers, and specialists with continuing education. SCADA allowed the dispatchers to control load flow quickly without the need for substation operators. SCADA had been installed or upgraded on about half of the higher voltage substations, and about 20 percent of the low voltage substations. SCADA is to be 100 percent installed by the end of 2001.

Although the substation operators were part of the regional T&D Construction organization, they performed switching procedures under the control of the dispatchers. The substation operators also inspected the substations and reported deficiencies to the dispatchers who prepared corrective maintenance *(CM)* work tickets. The regional T&D construction clerks inputted the work ticket to the Maximo substation database. Maximo is database software that stored and sorted substation equipment data, CM and preventive maintenance (PM) work tickets, and the preventive maintenance programs. It also communicated with substation work management software.

Except for not yet completed installation of system-wide SCADA control, substation operations were in accordance to good utility practices.

H. Substation Specifications, Inspection, Testing, and Maintenance

Standards

ComEd's Standards group determined substation equipment needs from substation planners, engineers, and the regional T&D construction personnel. The Standards group then prepared or updated standards to meet the needs. Included in the standards were "equipment specifications" for suppliers, indicating the physical requirements, electrical capabilities, and required factory tests to be performed on the equipment. ComEd equipment specialists performed in-factory witnessing of major equipment testing. ComEd specified substation equipment according to or in excess of IEEE requirements.

ComEd specified 132kV transformers for their 138kV system, which at first glance appeared to be an improper specification. However, 132kV was only the nominal rating and there were taps to operate the transformers from 125kV to 145kV. Those transformers could function (without saturating) up to 152kV. ComEd specified their 138kV transformers at 132kV to provide greater ability to maintain nominal distribution voltages under maximum loads.

Liberty found that ComEd's substation equipment specifications were adequate, updated, and, as applied to new construction and upgrades, in compliance with good utility practices.

Substation Inspections

ComEd's substation operators inspected substations periodically. These operators also sampled transformer oil for diagnostic tests. They reported deficiencies and prioritized the need for critical maintenance as follows:

00 Category – Immediately correct
10 Category – Correct within six weeks
20 Category – Correct within one year
30 Category – As necessary

The substation inspection schedules were somewhat informal and were not scheduled in Maximo. The substation operators tried to inspect the substations weekly and whenever switching was required.

Although they were qualified as substation mechanics, operators did not receive special training for inspecting substations. Also, the regions did not have maintenance engineers to provide technical supervision and quality control regarding equipment inspections. Except for lack of inspection training and technical supervision, the practice of using operators for substation inspections, and the use of the Maximo database, were consistent with good utility practices.

ComEd's Substation Maintenance Programs

ComEd used a Time-Based Maintenance *(TBM)* Program for scheduling substation maintenance, and was in the process of changing to a modern Reliability Centered Maintenance *(RCM)* program during the summer of 1999. The general maintenance procedures, actions, and schedules were indicated in the "Substation Equipment Maintenance Guide." Maintenance practices were indicated in the ComEd "Work Practices Manual."

The Maintenance Analysis Engineer entered the Preventive Maintenance (PM) programs into the Maximo database. The regional T&D Construction and Maintenance groups accessed the Maximo database to schedule preventive maintenance (PM) work.

Substation inspections were performed by the operators who reported substation equipment defects to the dispatchers. The dispatchers prepared corrective maintenance (CM) work tickets, and the regional T&D Construction and Maintenance groups entered the CM information into the Maximo database for scheduling purposes.

ComEd's RCM program attempted to optimize maintenance work and preserve the important functions of the equipment. It required that (1) the maintenance and operating history of the equipment be studied, (2) the functions of the equipment that need to be preserved be identified, (3) failure modes need to be identified and prioritized, (4) root causes of failures need to be identified, and (5) cost-effective inspection and preventive maintenance procedures need to be selected. Basically, part of RCM is time-based inspections and maintenance, and part is condition-based maintenance. Each major equipment item has or will have its own RCM program developed by equipment specialists and maintenance personnel, under the guidance of the Maintenance Analysis Engineer.

In August 1999, ComEd had a backlog of about 5,200 substation corrective maintenance tasks and some 20,000 preventive maintenance tasks. Because of this backlog, the RCM program could not be effectively initiated. One important RCM program that had been initiated was the oil sampling of TSS and TDC transformers and LTCs (load tap changers), transmission cables, and oil circuit breakers *(OCB)* for dissolved gas analysis (*DGA*). Oil, used to insulate and cool transformers, LTCs, and some transmission cables, produce particular gases when exposed to excess heat or voltage. DGA analysis can detect incipient defects that may develop in this equipment. ComEd's attempt to use an RCM program was consistent with good utility practices; however, ComEd's large maintenance backlog is not.

The RCM substation equipment maintenance programs and the work practices manuals were very comprehensive. ComEd's maintenance program included some routine and special diagnostic testing including capacitor tests; power factor tests on Type U bushings; transformer, LTC, and OCB dissolved gas analysis and oil dielectric tests; infrared thermographic inspection of connections; station battery tests; acoustic partial discharge tests; frequency response tests; and vibration analysis on very large transformers. Other important routine testing, including insulation and contact tests that were required in the new RCM program, had not been performed as part of the substation equipment program.

While aspects of ComEd's RCM program were superior, Liberty found other attributes of ComEd's maintenance program to be substandard. The ComEd substation maintenance programs lacked sufficient budgeting, supervision, or manpower such that maintenance tasks were not completed on a timely basis. Moreover, although both the older preventive maintenance program and the new RCM program indicated tests were to be performed on substation equipment, Liberty found no evidence to indicate that some of the insulation diagnostic tests were actually performed.

Examples of maintenance tests performed by other utilities are:

Transformers:

- Power-factor tests on insulation, bushings, and arresters to accurately detect moisture or other contamination problems that can cause premature failures.
- Excitation current tests to detect loose core laminations or distorted windings.
- Turns-ratio tests to determine shorted winding turns.
- Winding resistance tests to detect poor connections in transformers and LTCs.
- Oxidation tests to detect incipient and gross sludging of oil that will prevent proper cooling, deteriorate the cellulose insulation, and carry any free water to the cellulose insulation.

Circuit Breakers

- Insulation resistance and DC hi-pot tests to detect moisture and carbon contamination.
- Power-factor tests to accurately detect moisture contamination of the insulation systems.
- Contact resistance tests to detect high resistance connections, particularly at the contacts that may cause overloading and failure of the circuit breaker.

Substation Cables:

- ComEd had not performed DC hi-pot cable maintenance tests for some time. In 1993, an EPRI study indicated that performing DC high potential testing of some service-aged (more than a few years old) cross-linked polyethylene (XLPE) cable might be detrimental to the cable. Since the DC hi-pot testing may accelerate damage to XPLE cable, ComEd was correct for not using DC hi-pot tests on service-aged XPLE cable.

Since failures of cables within or leaving substations can cause substantial customer interruptions, it was important that ComEd have some means to evaluate cable condition. Although ComEd did not use the DC hi-pot test to evaluate service-aged cable, they had initiated programs using other test methods, and have replaced cables based on the results of those tests.

ComEd loaded some substation cables to emergency ratings, but had not documented the total overload times. No studies had been performed to determine if the excessive loading caused cable damage. Refer to Chapter Ten of this report.

ComEd's efforts to test substation cables using new methods was good utility practice. However, ComEd should intensify the maintenance testing programs for substation cables of all voltages and types, and should consider the use of proven DC hi-pot testing for non-XPLE cables.

Substation Inspections

Liberty inspected several of ComEd's substations. Some of Liberty positive findings from these inspections were:

- ComEd used "trip circuit test switches" to disable circuit breaker trips during relay tests. This was a good practice that is used by many electric utilities.

- In many TSS and TDC substations, ComEd had installed replications (mimic buses) of the transformers, circuit breakers, and buses in the substation. This helped operators determine how to switch complicated bus arrangements.

- ComEd maintained drawings in the TSS and TDC substations. Copies were kept in the regional office. Originals were kept in the ComEd headquarters office.

- Substation control rooms, and cable basements, were clean and tidy.

- Battery banks and cells appeared to be well maintained.

However, these inspections also found that:

- Some of ComEd's control and relay panel wiring was not identified to indicate the locations of the ends of the wires. When drawings are not available, this lack of wire identification may cause delays when attempting to resolve relay and control problems.

- Although ComEd specified LED indicating lamps for new substations, older substations had incandescent indicating lamps. Since indicating lamps also monitor the circuit breaker trip circuits, it is important that LEDs be used due to their long life. (See Chapter Seven.)

- ComEd did not use lightning shield wires over its substations. (See Chapter Eight.)

- Some older substations (*e.g.*, Forest Park, Crosby) had equipment in need of rust removal, patching, painting, and general repair.

- Cable basements were noted in most of the substations and fire detection systems were present. However, it appeared that there was still a relatively high potential for cable basement fires similar to those that occurred at the Bartlett and Pleasant Hills substations. (Refer to Chapter Seven.)

- Underground transmission line terminations had no lightning arresters. (See Chapter Eight.)

Substation Maintenance Expenditures and Equipment Failures

ComEd decreased substation maintenance expenditures from about $45 million in 1991 to about $15 million in 1998. From January 1988 to July 1999, TSS and TDC circuit breakers failed to operate at a rate of about 75 per year. TSS and TDC transformer failures were:

Year	Number	Total MVA
1999 to 6/26	14	609
1998	15	1,756
1997	9	645
1996	6	287
1995	8	820
1994	9	1,120
1993	11	889
1992	13	547
Totals	85	6,673

Assuming $8/kVA for repairs, a reasonable rule-of-thumb, this large transformer loss (from 1992 through June 1999) could amount to an estimated $50,000,000. Although poor maintenance cannot account for all failures, these data suggest that considerable savings and improved reliability could have been attained with improved substation maintenance. These figures do not include the failures of smaller transformers occurring at the SS, DC, and NC substations. On the basis of the Liberty team's experience, the number of circuit breaker and transformer failures during these periods were excessive.

I. Prior Consultant Recommendations

In March 1992, RMI issued a report to the ICC. That report included several recommendations related to ComEd's substations. In November 1995, Failure Analysis Inc. *(FaA)* reported on the results of its investigation of the July 1995 outages that ComEd had experienced. FaA issued several recommendations related to substations. This section reports on Liberty's evaluation of ComEd's response to those recommendations.

RMI recommended that ComEd should modify its current substation maintenance policies and practices in order to improve housekeeping. In particular ComEd's practice of storing unused protective relays in an uncontrolled manner should be abandoned. In response to that recommendation, ComEd said that its annual inspections will ensure proper housekeeping. During the course of its inspections of ComEd's substations, Liberty did not observe any housekeeping problems.

RMI recommended that ComEd should establish a process for controlling the apparatus manufacturer's instruction books and interconnecting wiring prints in substations. ComEd indicated that it had fully implemented this recommendation. ComEd also confirmed to Liberty that copies of all substation equipment instruction books and wiring drawings were kept in the substations. ComEd said that it kept master sets of all drawings in a central office.

RMI thought that ComEd should modify EMO (Equipment Maintenance Order) to include factors such as frequency of equipment operation. Moreover, RMI recommended that maintenance schedules should then be adjusted based on equipment usage and operation. ComEd said that it had fully implemented this recommendation. Liberty found that ComEd had changed to the newer Maximo database system.

FaA recommended that ComEd review the design and construction of Northwest Substation TSS114 Terminal 2 for age of equipment, ventilation of cubicles, and operation during outages. ComEd said that it had completed projects in response to the recommendation. Liberty witnessed some replacement work in progress at this substation.

FaA also recommended that ComEd enhance the planning of distribution substations for single-contingency outages, including review of allowable loadings, substation transformer capabilities, and availability of external ties. Among other things, ComEd said that it had assigned planners to the distribution dispatch center. Liberty found that ComEd's planning for distribution substations remained a problem. Refer to the conclusions and recommendations that follow and to Chapter Five– Distribution System Planning. Regarding planners stationed at the distribution dispatch center, refer to Chapter Nine.

FaA recommended that ComEd review the allowable loading limits for all distribution system equipment as a result of the July 12-16, 1995 operation, including conductors, cables, distribution transformers, and switchgear. ComEd did not agree with this recommendation. Liberty found that ComEd did not de-rate transformers to allow for contingencies. Refer to the conclusions and recommendations that follow.

FaA recommended that ComEd determine the ages of power transformers, circuit breakers, reclosers, and circuit switchers at all TSSs, TDCs, DCs, and SSs. ComEd should develop a computer database to track the ages, ratings, loadings, and maintenance data for this equipment. ComEd indicated that it tracks critical data in the Maximo database. Liberty confirmed that ComEd tracked these data in Maximo.

FaA recommended that ComEd improve the cubicle ventilation at TSS 114 Terminal 2. ComEd said that it had completed this project on March 30, 1996. Liberty verified ComEd's statement to be correct.

FaA said that ComEd should transfer four of the most heavily loaded 12.5kV distribution lines from Terminal 2 to Terminal 3 at TSS114, so as to provide load relief for Terminal 2. ComEd indicated, and Liberty verified, that it had also completed this project on March 14, 1996.

FaA said that ComEd should replace the Allis Chambers current transformers *(CTs)* for power transformers at Hanson Park and Cicero. Also, ComEd should evaluate replacement of Allis Chambers CTs for 12.5 kV bus ties at TSS 114 Terminal 2, Hanson Park, and Cicero. ComEd said that it had replaced power transformers and the Allis Chambers transformer breaker CTs, but had determined that replacement was not required for the bus tie CTs. Liberty agreed with ComEd that a CT overloading condition was not likely to recur.

FaA recommended that ComEd develop a long-term plan to upgrade Terminal 2 with new 12.5kV circuit breakers or replace Terminal 2 entirely at TS114. ComEd said that planning was in progress and that the expected in-service date was early 2001. Liberty observed this work and found that ComEd planned to complete the project in the Spring of 2000.

FaA recommended that ComEd maintain adequate quantities of spare CTs and circuit breakers in stock. ComEd said that its spare CTs had been upgraded and that spare circuit breakers had been refurbished. ComEd had approximately 200 spare current transformers in stock.

FaA recommended that at the Frankfort substation (TSS140), ComEd should pursue and expedite the completion of the Mokena TDC project, including the installation of a second substation transformer. ComEd said that it had completed these projects. Liberty confirmed that the projects had been completed.

FaA recommended that at the Frankfort substation (TSS140), ComEd should provide additional external ties to distribution lines from sources adjacent to TSS 140. ComEd stated that this project had also been completed. Liberty confirmed that the project had been completed.

FaA made three recommendations related to the Troy substation (DCJ17). First, ComEd should provide an alternate 34.5kV source for the substation. Also, they should provide a split bus structure with normally open bus tire breaker on the secondary side of the transformers. This bus tie should be equipped with automatic reclosing capability. ComEd offered an alternative arrangement. Liberty found that ComEd had installed a 34kV automatic sectionalizing scheme at this location. Second, FaA said that ComEd should provide more external ties from other adjacent sources in the area. ComEd said that this had been completed. Finally, FaA said that ComEd should initiate a pilot program to install radio controlled sectionalizing switches on the two distribution lines out of DC J17, and their ties. During contingencies at DCJ17, switching loads to external ties could then be done remotely via supervisory control and data acquisition

(SCADA), thereby reducing outage duration. ComEd indicated that it had partially completed this effort. Liberty confirmed that ComEd planned to complete this project during the year 2000.

FaA made four recommendations related to the Braidwood substation (DCJ69). These were: (1) reconfigure DCJ69 as recommended for DCJ17, Troy (ComEd offered an alternative arrangement); (2) provide more external ties from other adjacent sources in the area (ComEd said it had installed a third transformer); (3) install radio controlled sectionalizing switches on the two distribution lines out of DCJ69 and their ties (ComEd said it was partially complete); and (4) complete the planned replacement of the substation transformers with 9.375 MVA transformers by June 1996 (ComEd said it had added a third transformer). Liberty found that ComEd had installed a 34kV automatic sectionalizing scheme at this location. The radio-controlled sectionalizing switches were to be completed during 2000. Finally, Liberty verified that the third transformer had been added.

With regard to the Sandwich substation (SS314), FaA indicated that ComEd should replace the 6.250 MVA transformer with a 9.375 MVA transformer by June 1996, or add a third substation transformer, in order to provide adequate station capacity. ComEd said it had implemented this recommendation. Also, FaA said that ComEd should provide more external ties from other adjacent sources in the area. ComEd said that the three transformers now have sufficient capacity. Liberty verified the implementation of this recommendation.

III. Conclusions

General Objectives

The first four of Liberty's conclusions relate to the general objectives set out for this evaluation. More specific conclusions follow these first four.

1. **ComEd's planning and loading of its substations was not consistent with good utility practices.** (Recommendations Eleven-8 through Eleven-13.)

ComEd's planning for substation loading was not consistent with good utility practice because it did not include sufficient margins for unexpected contingencies, such as very high ambient temperatures, and was not always accurate. Because planning was inadequate, transformers were operated in excess of ratings. According to ComEd's own study, if the summer peak temperatures in 2000 match those experienced in 1999, the loading on about 30 percent of the TSS and TDC transformers and 16 percent of the feeders will exceed ComEd's normal rating. Unless specific capacity relief projects are completed, and if the weather conditions are repeated, a few of the transformers will exceed 120 percent of the normal rating. This expected and very possible loading is the result of inadequate planning.

2. **ComEd's substation construction and upgrade planning was not adequate for providing reliable service.** (Recommendation Eleven-6.)

Needed substation upgrades at Northwest and LaSalle had not been executed in time to provide additional back up to equipment that failed in the summer of 1999. Construction and upgrading were not performed so that overload conditions would not occur.

3. **ComEd's design for substations provided adequate redundancy to prevent customer outages during maintenance periods and unscheduled equipment outages.**

Redundancy in ComEd's substation designs, where needed, was consistent with good utility practices. However, operating substation transformers at the normal capacity, without the margins necessary to allow picking up additional loads, and then exceeding normal ratings defeats the purpose of redundant transformers.

4. **ComEd's substation equipment inspection, testing, maintenance, repair, upgrade, and replacement practices did not effectively minimize unscheduled equipment**

outages and were not consistent with good utility practices. (Recommendations Eleven-1, Eleven-3, Eleven-6, Eleven-7, and Eleven-14 through Eleven-19.)

Substation maintenance was hampered by not having an organizational element solely responsible for substation maintenance. ComEd's substation testing was insufficient to properly identify maintenance problems. Substation maintenance tasks were backlogged by more than one year. Good utility practice would allow backlogs to occur only to delay first contingency outages during summer peak periods.

Substation Organization

5. ComEd had no separate substation construction and maintenance group. The regional T&D construction organizations were responsible for distribution system maintenance as well as substation construction and maintenance. (Recommendations Eleven-1 and Eleven-2.)

Although transmission substations may be larger and somewhat more complex, all substations, both transmission and distribution, have similar equipment and have similar construction and maintenance challenges. Conversely, construction and maintenance of substations have very little in common with construction and maintenance of transmission and distribution systems outside of the substations.

Distribution system construction requires the skills of electricians (linemen) and equipment (*e.g.*, line trucks, diggers) to build overhead and underground lines. Substation construction requires substation mechanics to assemble and wire complicated control and relay panels, set and assemble heavy and complicated equipment such as high voltage oil and SF6 circuit breakers[a] and oil-filled power transformers.

Distribution maintenance of several thousand miles of overhead and underground includes tree-trimming, replacing fuses, locating overheated connections, replacing overhead wires, and pulling replacement underground cables, repairing poles and equipment on poles, and locating and repairing underground cable faults. In contrast, maintenance of the 2,750 substations in ComEd's system includes inspections, preventive maintenance, predictive tests, and corrective maintenance of transformers, circuit breakers, circuit switchers, buses, and complicated control systems.

a. SF6 circuit breakers are insulated with a gas-sulfur hexafloride.

The procedures, personnel skills, and equipment necessary to construct and maintain distribution circuits and substations are very much unique and unrelated, and each group of skilled employees must be supervised by those who are knowledgeable in one or the other. Additionally, for assuring proper efficiency and quality control of the work performed on the sizable number of substations in each region requires the undivided attention of regional substation construction and maintenance management. Regional substation management should (1) track construction and maintenance procedures, man-hour usage, and schedules, (2) ascertain that training of substation engineers and mechanics is sufficient to maintain a good level of quality, and (3) verify the quality of the substation construction and maintenance work performed. A utility the size of ComEd should organize these special skills and equipment required for substation work separately from distribution work.

Skilled Personnel

6. ComEd's substation mechanics may have needed additional training for performing substation equipment maintenance and minor testing (Recommendation Eleven-3.)

Liberty observed substandard 12kV circuit breaker maintenance practices at the Kingsbury-Ohio substation, and later observed a contractor technician performing similar maintenance work properly at the Crosby substation. The contractor technician also performed tests on the circuit breakers, which were not being performed by the ComEd crew.

Contracting

7. During a period in which it had a large backlog of maintenance work, ComEd pursued work for its own skilled workers on non-ComEd owned equipment. (Recommendation Eleven-4.)

As of August 1999, ComEd had a substation maintenance backlog of about 25,000 items. While this backlog was building, ComEd was pursuing work for its people on non-ComEd-owned equipment and systems. While the work for some of these outside projects may have had a relation to ComEd's system reliability, ComEd appeared to be giving the sale of ComEd's skilled employees for outside projects some priority over the need to reduce its own backlog.

8. ComEd was not using qualified substation maintenance contractors to perform regular substation maintenance work. (Recommendation Eleven-5.)

Although contractors performed some specialized testing work for ComEd, they could have been used to further reduce (or prevent) large maintenance backlogs There are many qualified companies in the Northern Illinois/Chicago area.

Construction

9. ComEd had high quality substation construction and upgrade projects, but many of the projects were delayed. (Recommendation Eleven-6.)

The quality of the construction of substation upgrades was consistent with good utility practices. However, some of the substation construction and upgrade projects had been delayed, at least partially due to budget limitations. ComEd delayed the completion of the important upgrades at the Northwest and LaSalle substations.

10. The installation of ComEd's new "Concept" substations was a good utility practice.

These "bought-as-a-unit" substations have many advantages over the older style substations that were assembled piecemeal. The advantages of concept-constructed substations are lower cost, speed of installation, standardization, and quality. The use of "concept" substations for new construction and to upgrade old substations is encouraged.

Operations

11. ComEd's transmission and distribution dispatching centers' facilities, manpower, and equipment were consistent with good utility practices.

The Transmission Bulk Power Center and the Distribution Dispatch Center are of the highest quality and are staffed by qualified dispatchers. The dispatchers needed more timely planning data from the planning group and more intensified training to handle any type of emergency that may occur. The incomplete status of the SCADA system had decreased the ability of the distribution dispatchers to monitor and control the distribution substations. When SCADA is complete, distribution system reliability will be enhanced. Despite these shortcomings, and as it related to substations, Liberty concluded that ComEd's dispatching facilities and personnel were of the highest quality. Refer to Chapter Nine of this report.

RELAP

12. While ComEd's Remaining Economic Life Assessment Policy *(RELAP)* was a good utility practice, it could have been improved. (Recommendations Eleven-7, Eleven-13, and Eleven-14.)

The RELAP program was a good utility practice, and was well conceived, but had some problems. It was difficult to amass a large group for the on-site substation review. RELAP candidate substations could have been on a waiting list for months. Other than performing dissolved gas-in-oil tests on transformers, LTCs, and OCBs, ComEd had an insufficient comprehensive diagnostic testing program necessary to ascertain the condition (and expected service life) of substation equipment components. RELAP did not have complete data indicating equipment overloading history. Therefore, to determine if equipment was a "poor performer," the equipment had to have failed to operate properly. An example of a substation on the RELAP list was Forest Park TDC. Liberty observed that an outdoor switchgear enclosure was rusting, and the internal heaters did not appear to be operating. Rust indicated that moisture may have entered the switchgear. Insulation resistance and hi-pot tests would have been required to determine the condition of the switchgear insulation. Also, the three 47-year-old transformers were leaking oil badly requiring expensive regasketing. The transformers should have been tested (including insulation resistance and power-factor and turns ratios tests) to determine if they had sufficient life expectancy to consider repairs. However, testing was not part of the RELAP program.

Planning and Transformer Load Ratings

13. ComEd's planning of projected substation loads sometimes failed to meet good utility practice. (Recommendations Eleven-9 and Eleven-12.)

As indicated in ComEd's five-year distribution planning study, the expected future substation transformer loads sometimes were off-target. ComEd did not de-rate transformers to provide any margin for excessive load and operating temperatures due to very high ambient temperatures. Refer to Chapter Five of this report.

Planning estimates were not accurate. Planners generally increased planned loads only at a rate of 1-2 percent per year, but actual loads varied more than this. Examples of substation transformer planned peak summer loads:

- TSS 152 Busse TR 71 – The actual load decreased by 19 percent during the period of 1994 to 1998. Planning had predicted a 1-2 percent per year increase.

- TSS 35 Lakeview TR 2 – The actual load increased by 31 percent during the period from 1994 to 1998. Load relocation accounted for only about 1 MVA of load. Planning had predicted a 2-4 percent per year increase.

ComEd's substation designs included adequate redundancy, but operating substation transformers at the normal capacity without the margins necessary to allow picking up additional loads without exceeding normal ratings defeated the purpose of redundant transformers.

14. ComEd could not justify the summer normal and emergency transformer ratings in terms of accepted loss-of-life. Therefore, the use of these ratings could have reduced transformer life to the point that system reliability was affected. (Recommendations Eleven-10 and Eleven-11.)

Liberty could not thoroughly evaluate ComEd's transformer ratings due to lack of data. Liberty's request for loss of life calculations referred only to the IEEE standard, without providing data and ComEd's assumptions necessary to verify the ratings. Based on assumptions made by Liberty, the ComEd's substation transformer normal ratings were appraised as slightly excessive, and emergency ratings were somewhat more excessive, when compared to the guidelines contained in IEEE standards. ComEd's lack of coordination of an acceptable transformer loss-of-life with allowed operating temperatures and loading formed the basis for Liberty's conclusion.

15. ComEd did not have procedures to record and minimize transformer "loss-of-life." (Recommendations Eleven-13, Eleven-14, and Eleven-15.)

Monitoring, archiving, and analyzing winding temperatures and accumulated over-temperature conditions could have helped to predict transformer problems. The actual operating history of each transformer should have been compared with the assumptions made for the accepted transformer loss-of-life calculations, which may not exist. ComEd performed dissolved gas analyses (*DGA*) to determine when insulation damage had possibly occurred due to overloading. Although Liberty agrees that these tests provide valuable information to determine when loss-of-life has occurred, depending only on it to monitor loss-of-life was reactive rather than proactive.

Substation Designs

16. ComEd's substation designs provided reliability as required and were generally consistent with utility practices.

Liberty found ComEd's basic substation design to be consistent with good utility practices. However, as noted in Chapter Eight, there was inadequate lightning protection at some substations, and underground transmission line terminations and the transformer secondary windings were not protected by lightning arresters. Liberty also noted that ComEd parallels transformers in the Chicago TSS and TDC substations to balance transformer loads and provide for uninterrupted service if a transformer fails. While this is a practice used by some other utilities, there are negative aspects including increased stress on the transformers, possibly excessive neutral voltages and harmonics, and possibly excessive circulating currents.

17. ComEd's substation equipment specifications were consistent with good utility practices.

ComEd's substation equipment specifications were in accordance with or exceeded applicable ANSI/IEEE standards. For example, ComEd had been specifying that transformer 12kV windings be rated to withstand lightning voltage surges of 110kV (BIL), rather than the IEEE required 95kV.

Substation Maintenance

18. Substation maintenance was inadequate and not consistent with good utility practices. (Recommendations Eleven-2, Eleven -4, Eleven-5, and Eleven-16 through Eleven-18.)

As of August 1999, over 25,000 substation maintenance tasks were overdue. This was likely due to (1) a lack of regional substation organizations including maintenance engineers, (2) reduced maintenance budgets, (3) use of ComEd mechanics on outside projects, and (4) not using qualified substation maintenance contractors. Also, ComEd's maintenance program did not include sufficient diagnostic testing procedures, nor did ComEd have substation testing crews to perform the more complicated tests necessary as part of sound equipment maintenance. A nearby utility with fewer substations and half of ComEd's load, has 18 substation maintenance and testing crews, plus 11 more crews that specialized in performing insulation power-factor test.

This utility used 11 power-factor test sets and 12 circuit breaker motion analyzers.[b] ComEd has one of each. The test set and the systems shop electricians, who sometimes were not available when needed, performed the special testing work, usually for commissioning tests or problem solving.

Liberty observed ComEd mechanics performing 12kV circuit breaker maintenance. They did not have a copy of their work procedures, did not perform any tests to verify the electrical integrity of the breaker, used an improper lubricant, and left exposed breakers out in the damp air.

19. ComEd attempted to determine the quality of its aged electrical cables by experimental testing. (Recommendation Eleven-19.)

New cables rarely fail. Cables that are a few years old usually fail due to improperly installed stress relief devices at the ends (terminations) and the joints (splices). Old cable, particularly the extruded plastic (XLPE) insulated cables exposed to water, usually fail due to multiple minuscule voids called "water trees" formed due to electrical stress and water. Industry standard testing of new cables is the DC hi-pot test. If properly performed, it will detect improperly installed terminations and splices. Presently, there is no industry standard method for testing aged XLPE cable that has been damaged by "water treeing."

A 1993 EPRI study showed that DC hi-pot testing of aged extruded plastic cable may actually increase the failure rate of XLPE insulated cable that had been already damaged by "water trees." EPR (rubber) insulated and oil/paper insulated cables can be DC hi-pot tested regardless of age. Years ago, ComEd used DC hi-pot testing to evaluate the condition of all cables. DC hi-pot buses actually are installed in several substations. About ten years ago, ComEd determined that the DC hi-pot testing method used was detrimental to their aged cables, and stopped performing tests, no matter how the cables were insulated. ComEd performed DC hi-pot testing on new cables, and many cables that had been spliced. Other utilities still perform DC hi-pot maintenance tests on cables, especially EPR and oil/paper lead covered cables.

Although ComEd did not use DC hi-pot maintenance testing on a regular basis, they had on-going cable test pilot programs, including one called tan-delta. Other utilities are using these diagnostic tests and ComEd should continue evaluating cables, especially XLPE, using these methods.

b. Cinergy Corp, Plainfield IN and Cincinnati, OH.

IV. Recommendations

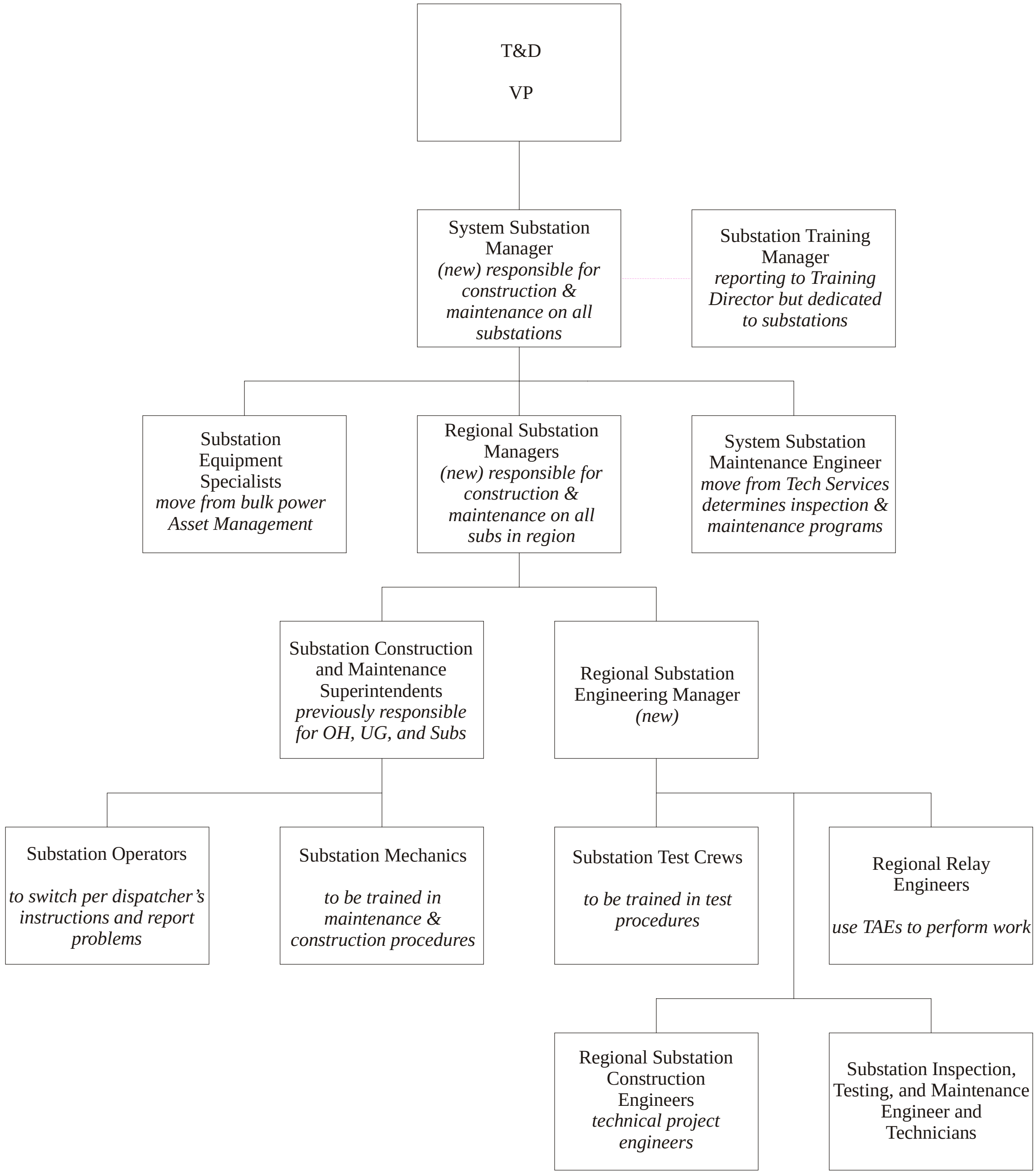
Eleven-1 ComEd should improve the organization responsible for substation construction and maintenance.

To improve substation maintenance and testing, and to promote individual accountability and group communications, ComEd should consider the benefits of a substation organization including the positions listed below and shown on the following chart.

- System Substation Manager
- System Staff Substation Maintenance Engineer and Equipment Experts
- Regional Substation Manager
  - Regional Substation Construction and Maintenance Superintendents
    - Substation Construction and Maintenance Mechanics
    - Substation Operators
    - Regional Substation Test Crews (mechanics)
  - Regional Substation Engineering Manager
    - Regional Substation Construction Engineers
    - Regional Relay Engineers (TAEs)
    - Regional substation Inspection, Testing, and Maintenance Engineers

As compared to the organization figure shown earlier in this chapter, the recommended organization would be along the lines displayed in the figure below.

This is a medium priority recommendation that should be implemented by December 31, 2000.


T&D
VP
System Substation Manager
(new) responsible for construction & maintenance on all substations
Substation Training Manager
reporting to Training Director but dedicated to substations
Substation Equipment Specialists
move from bulk power Asset Management
Regional Substation Managers
(new) responsible for construction & maintenance on all subs in region
System Substation Maintenance Engineer
move from Tech Services determines inspection & maintenance programs
Substation Construction and Maintenance Superintendents
previously responsible for OH, UG, and Subs
Regional Substation Engineering Manager
(new)
Substation Operators
to switch per dispatcher's instructions and report problems
Substation Mechanics
to be trained in maintenance & construction procedures
Substation Test Crews
to be trained in test procedures
Regional Relay Engineers
use TAEs to perform work
Regional Substation Construction Engineers
technical project engineers
Substation Inspection, Testing, and Maintenance Engineer and Technicians

Eleven-2 ComEd should promote accountability and responsibility for substation maintenance.

ComEd should consider using regional "Maintenance Engineers" to inspect maintenance and testing work performed, and to evaluate inspection comments and recommendations made by substation operators. They should take responsibility to see that corrective actions are made. These maintenance engineers in each region should ascertain that all inspection, testing, and maintenance practices are accordance with the RCM program and work procedures.

This is a medium priority recommendation that should be implemented by December 31, 2000.

Eleven- 3 ComEd should review and upgrade as necessary the substation training programs for substation mechanics

Liberty observed poor circuit breaker maintenance practices performed by ComEd substation mechanics including not following the specific work procedures checklist, using improper lubricant, not performing diagnostic tests (at least insulation resistance and contact resistance) to prove that the circuit breakers were suitable for service, and leaving 15kV circuit breakers exposed to wet air.

This is a low priority recommendation that should be implemented by June 1, 2001.

Eleven- 4 ComEd should only perform work on non-ComEd equipment when that work is critical to the reliability of ComEd's system.

With a large backlog of its own maintenance tasks to perform, ComEd should not be pursuing construction, maintenance, and repair work on non-ComEd owned equipment. ComEd should agree to perform such work only if critical to the operation of ComEd's system.

This is a low priority recommendation that should be implemented by December 31, 2000.

Eleven-5 ComEd should use outside contractors for substation maintenance to reduce the maintenance backlog.

To meet substation maintenance schedules and to make use of the expertise of others, ComEd should consider using the services of qualified substation testing and maintenance contractors to supplement ComEd mechanics, when needed to maintain maintenance schedules.

This is a medium priority recommendation that should be implemented by December 31, 2000.

Eleven-6 ComEd should complete upgrade work that is planned.

ComEd should complete its SCADA system per scheduled completion date of December 31, 2001. ComEd should complete planned upgrade work at the LaSalle and Northwest substations as soon as possible, to prevent recurrence of problems of July-August, 1999.

This is a high priority recommendation that should be implemented as soon as possible.

Eleven-7 ComEd should improve the RELAP program.

The RELAP organization should consider using substation inspection specialists from other utilities or substation testing firms to inspect and help qualify substations for maintenance, replacement, or upgrade.

These other experts can provide a wealth of knowledge and experience to assist the RELAP engineers determine equipment with high failure risk, and help determine the inspection and diagnostic testing procedures necessary to determine estimated reliable life in substation equipment.

ComEd should move RELAP to the substation organization. By working under the system substation manager, RELAP would be held responsible for the substation upgrade programs.

RELAP should have the authority to order additional diagnostic testing (primarily insulation tests) of substation equipment needed to properly evaluate equipment condition. It is important that RELAP have appraisals of equipment condition not only on the basis of inspections and past operation and maintenance history, but also on the results of recent diagnostic testing.

This is a medium priority recommendation that should be implemented by June 1, 2001.

Eleven-8 ComEd should de-rate transformers to allow a planning margin that will minimize overloading of transformers.

A review of ComEd planning records indicates that estimating future loads is not an exact science. The de-rating contingency will provide greater lead-time to plan corrective actions before overloading may damage transformers. The planned loads for four transformers selected at random indicated the actual maximum loads for the period 1994 to 1998 ranged from a decrease of 19 percent to an increase of 31 percent. The planners used an annual estimated increase of 1-2 percent for these substations.

ComEd should include at least three factors when planning transformer loading. These are: (1) de-rate transformers to allow for margins necessary due to possible errors in estimating future loads, (2) de-rate transformers that have experienced thermal overloading, and (3) include margins that allow a transformer to pick up part of another transformer's load without exceeding the normal ratings during hot weather. The actual "de-ratings" should be based on these issues for each transformer.

This is a high priority recommendation that should be implemented by June 1, 2001.

Eleven-9 ComEd should use more conservative weather adjustments in planning for loading on substations. (Refer to Chapter Five on Distribution System Planning.)

This is a high priority recommendation that should be implemented by December 31, 2000.

Eleven-10 ComEd should determine acceptable transformer loss-of-life.

Since ComEd's basis for summer normal and summer emergency transformer load ratings imply that some loss-of-life is expected, ComEd should define and justify the loss-of-life associated with its ratings. By forcing this kind of a determination, and by recording loss-of-life data as recommended earlier, ComEd will be in a better position to make sound economic and reliability decisions.

This is a medium priority recommendation that should be implemented by June 1, 2001.

Eleven-11 ComEd should have a formal, technical review made of its transformer loading criteria.

The transformer load ratings, based on ComEd's accepted transformer loss-of-life, should be reviewed by transformer engineers to verify that the ratings are correct, or suggest other ratings. While ComEd reviewed these loading criteria before, those reviews were not based on a stated and accepted loss-of-life.

This is low priority recommendation that should be implemented by June 1, 2001.

Eleven-12 ComEd should take action to relieve overloading on TSS and TDC transformers and cables on the basis of realistic temperature predictions.

ComEd expects that some transformers and cables may be overloaded during the summer of 2000 if reinforcement projects are not completed and the temperatures experienced in 1999 are repeated.

This is high priority recommendation that should be implemented by December 31, 2000.

Eleven-13 ComEd should maintain thermal load records for substation transformers.

Whenever transformer winding temperatures exceed 100ºC, temperature-time records should be maintained as a thermal-load history of the transformer using PI-historian. The substation maintenance engineers and the RELAP group should analyze these records. These engineers can then evaluate the need to (1) intensify DGA testing on transformers that have been overloaded, and (2) determine the need to upgrade to a larger transformer. Presently, only the results of DGA testing is used as a guide for replacing or upgrading TSS and TDC transformers.

This is medium priority recommendation that should be implemented by June 1, 2001.

Eleven-14 ComEd should conduct tests whenever a substation transformer experiences a temperature alarm.

ComEd should conduct dissolved gas tests and possibly Furfural tests[c] on transformers that exceed the "normal" alarm temperature. The substation maintenance engineer and the RELAP group should analyze the results. By the results of these tests loss-of-life can be estimated.

This is medium priority recommendation that should be implemented by December 31, 2000.

Eleven-15 ComEd should intensify testing and maintenance for transformers that may be heavily loaded.

c. Furfural is produced by the thermal degradation of cellulose in oil. The theoretical age of the cellulose can be analytically determined by furfural content of oil in a transformer.

For transformers that may be loaded near or in excess of the summer normal ratings, the radiators should be cleaned, temperature gauges calibrated, alarm set points and circuits verified, and a benchmark DGA test performed. These good utility practices should be performed in the spring or early summer. Also, the installation of thermal recording devices, if not already installed, should be considered.

This is medium priority recommendation that should be implemented by December 31, 2000.

Eleven-16 ComEd should reduce the substation maintenance backlog.

The work on all backlogged substation maintenance items should be intensified on the basis of priority and outage opportunities. ComEd should consider using the services of substation maintenance firms to supplement the ComEd crews. The new RCM program cannot be fully effective until the past maintenance is on schedule.

This is high priority recommendation that should be implemented by December 31, 2000.

Eleven-17 ComEd should establish substation test crews.

In order to perform the RCM required testing work, ComEd should have "substation testing crews," similar to those used by other utilities. The crews should be equipped with special vehicles and test equipment. These crews should receive special training in the operation of test equipment and the analysis of data. Maintenance engineers would provide technical guidance to the test crews.

This is medium priority recommendation that should be implemented by June 1, 2001.

Eleven-18 ComEd should consider having Substation Maintenance Programs reviewed by others.

ComEd should consider assembling a team of substation equipment maintenance experts made up of engineers from other utilities and several qualified substation inspection, testing, and maintenance contractors. This team would review ComEd's substation maintenance programs and help ComEd make determinations of the optimum procedures to follow and the best tools and materials to use based on the best judgments and experiences from the substation maintenance industry.

This is low priority recommendation that should be implemented by June 1, 2001.

Eleven-19 ComEd should evaluate all available cable testing procedures.

Because cable failures caused 11 percent of ComEd's interruptions, and cable testing wasn't performed for ten years, ComEd should continue its pilot cable testing programs. ComEd should also consider formally evaluating all available cable maintenance testing procedures. ComEd should assemble a team of cable testing experts from ComEd, other utilities, and professional cable testing firms to share knowledge of the various procedures, and evaluate the advantages of the various test methods (including DC hi-pot on non-XLPE cables).

With a large number of cables to test, a ten-year program could be established to perform maintenance tests on all cables. Therefore priorities are necessary. Liberty recommended in Chapter Nine to place priorities based on high failure rates and number customers interrupted by a failure. All cables leaving substations should be included in the latter category because of the potential for affecting large numbers of customers.

This is medium priority recommendation that should be implemented by December 31, 2000.